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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	R.16-02-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PORTFOLIO AND RELATED POLICY ACTIONS

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CalCCA	California Community Choice Association
CAISO	California Independent System Operator
CEC	California Energy Commission
CCA	Community Choice Aggregator
CCGT	Combined Cycle Generation Turbine
DAM	Day Ahead Market
DCPP	Diablo Canyon Power Plant
ELCC	Effective Load Carrying Capability
EO	Energy Only
FCDS	Full Capacity Deliverability Status
FOM	Front of the Meter
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt Hour
HASP	Hour Ahead Scheduling Process
IOU	Investor Owned Utility
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
LCR	Local Capacity Requirement
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MMT	Million Metric Tons
MW	Megawatt
MWh	Megawatt Hour
O&M	Operations and Maintenance
OOS	Out-of-State
OTC	Once Through Cooling
PCM	Production Cost Modeling
PSP	Preferred System Portfolio
RA	Resource Adequacy
RSP	Reference System Portfolio
RTM	Real Time Market
SCE	Southern California Edison Company
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
TPP	Transmission Planning Process
WECC	Western Electricity Coordinating Council

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

1. The Reference System Portfolio does not "over-rely" on solar and storage resources given current expectations of technology performance and associated modeling results over a range of modeling scenarios. However, future IRP cycles should revisit this concern as more experience is gained with these technologies on the scale conceived in the RSP. This uncertainty highlights the need for the Commission to avoid directives that risk imposing unnecessary stranded investment costs on customers. **Solar Reliance** **Storage Reliance**

2. Assessing criteria pollutant impacts of fossil resources, considering the rate of criteria pollution (*e.g.,* grams per megawatt-hour), gross production of criteria pollution (*e.g.,* kilograms), and damage to human health in populated zones (*e.g.,* Disability Adjusted Life Years), in modeling will facilitate prudent decision-making regarding the "least regrets" thermal generation to be retained for reliability as California transitions toward a fully decarbonized grid. **Thermal Generation** **Criteria Pollutant Metrics**

3. While import availability may decline over time, as coal plants in the West retire and other states implement increasing levels of renewable portfolio standards, the static import constraints in SERVM and RESOLVE do not accurately reflect California's near-term or perhaps mid-term realities. The SERVM model assumptions reflect the planned WECC resource retirements, yet do not identify reliability shortfalls unless the artificial import constraints are applied. Staff should thus remove these constraints or develop a trendline showing a decline in availability over the planning horizons recognizing the timing of WECC-wide retirements and increases in carbon-free procurement. **Import Assumptions**

4. If, after adjusting for more realistic levels of imports, a need for additional "generic effective" capacity remains to meet a loss of load expectation of less than 0.1, Staff should test various resource- and location-specific solutions (*e.g.*, longer duration batteries) to better understand the quantity and type of need, rather than assuming a lump sum of generic capacity. **Generic Effective Capacity**

5. To target better solutions requires greater accuracy in busbar mapping, which should be prioritized in this proceeding and subject to additional stakeholder input. **Busbar Mapping**

6. The accuracy of the baseline resource assumptions could be improved by: (1) adding all new build resources contracted by all load-serving entities; (2) expanding coordination with other WECC-wide regulatory agencies to understand resource retirements and load forecasts to inform market interactions; and, (3) vary assumptions for storage duration from the current assumption of 1,479 MW of four-hour duration battery storage by 2030. **Baseline Resources Assumption**

7. A CalCCA sensitivity case shows that assuming longer duration storage in the near-term

reduces the duration of incremental storage resources, especially in years 2022 and 2026. Sensitivity cases should be added to the IRP modeling to identify an appropriate mix of battery configurations for system needs, including at least a subset of battery storage capacity needs to have an eight- to nine-hour duration. **Battery Storage Duration**

8. SERVM should isolate Diablo Canyon Power Plant impacts on reliability needs using an "in/out" methodology to identify any system resource adequacy deficiency that should be allocated to all load-serving entities within the three Transmission Access Charge areas in proportion to their load ratio share. **Diablo Canyon Impacts**

9. The Commission should replace SERVM, for the next IRP cycle, with a production cost model that models security-constrained unit commitment and security-constrained economic dispatch (*e.g.,* PLEXOS, GridView, UPLAN, GE MAPS, Power System Optimizer (PSO), or AURORA). **Production Cost Modeling**

10. The 46 MMT Alternate Scenario should be used for reliability and policy-driven bases cases for the next CAISO Transmission Planning Process, provided a robust feedback loop is established between the IRP and the TPP that includes stakeholder feedback on the busbar mapping process. **CAISO TPP Base Case**

11. Greater flexibility in the aggregation process for the 2020 Preferred System Portfolio to allow load-serving entities to better reflect individual policy and legal drivers and to incorporate more current and granular data will improve the accuracy and reliability of the IRP outcome. **Plan Aggregation**

12. The Commission should not rely on these comments to make decisions about resource development (*e.g.,* **geothermal** or **pumped storage**) or **transmission** development, but should limit the use of the comments to refining its modeling assumptions, base cases and other related matters. The need for extraordinary resource development, if considered at all, should be taken up as the Commission considers the adoption of a Preferred System Portfolio.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION
COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PORTFOLIO

The California Community Choice Association[1] submits these Comments in response to the *Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio* issued on November 6, 2019 (Ruling).

I. INTRODUCTION

CalCCA appreciates the great strides made by Commission staff in advancing IRP modeling between the 2017-2018 Reference System Plan and the 2019-2020 Reference System Plan. These advances, supported by additional adjustments as this Integrated Resource Planning process advances, will increase the likelihood of California's success in decarbonizing the grid while maintaining reliability. Despite these advances, however, some level of uncertainty in the IRP process is inevitable. These comments identify several factors that give rise to uncertainty—length of planning horizons, pace of decarbonization, levels of available imports, and accuracy of busbar mapping—and encourage the Commission to manage these issues in a

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[1] California Community Choice Association represents the interests of 19 community choice electricity providers in California: Apple Valley Choice Energy, CleanPowerSF, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, and Valley Clean Energy.

way that promotes the accuracy and reliability of the IRP outcomes and procurement flexibility over the long run.

The *planning horizon* will materially affect the level of uncertainty in the IRP output. Near-term estimates of capacity expansion resource needs can be modeled with some degree of confidence, but technological innovation, resource availability, and project economics are likely to shift dramatically throughout the 2020s, leaving little certainty regarding the precise portfolio mix required in the mid- and long-term. Thus, as the Commission moves forward in the IRP process, the identification of resource portfolios will become firmer. For example, a strong indication that LSEs will rely on OOS wind resources, taking into consideration the cost of the resulting new transmission infrastructure, may justify the need for including those resources in the default (base) portfolio. Set in this light, the significant capacity of solar and Li-Ion battery storage included in the RSP does not necessarily equate to "overreliance" in the mid- to long-term. Any conclusions drawn from this IRP cycle must recognize planning horizon uncertainty and accommodate changes in resource mix over time.

The unprecedented *pace of decarbonization* further raises the level of uncertainty. The transition to a fully decarbonized grid will require revision and course-correction throughout the process to address technical and economic realities that arise along the path. In modeling this transition, particular attention should be given to what portion of the existing gas-fired generation fleet should be retained or retired within the IRP planning horizons. Using criteria pollutant levels as a metric, as CalCCA has proposed, provides greater granularity on the impacts of these resources in making this calculation. Retention of a simple cycle turbine will have materially different impacts than the retention of a CCGT, and retention of a high capacity factor CCGT will have materially different impacts from retention of a low capacity factor unit.

Retention of some amount of thermal generation may be appropriate to mitigate threats to reliability as the state gains better experience with existing technologies and develops new technologies to reduce reliance on thermal generation. The IRP process should enable LSEs to plan carefully for swift and orderly decarbonization with attention to ensuring a thoughtful and robust approach, enabling resources put into place to operate as planned, and avoid risky and expensive investments.

The uncertainty surrounding the *level of available imports* further complicates the IRP process. However, the RSP's 5 GW constraint on imports for all hours in economic dispatch of the model, which produces a need for 2,000 MW of "perfect" capacity, is counterproductive. Exacerbating the problem, Staff's newly proposed approach, presented on November 4, 2019, constrains imports not only for RA purposes, but also for energy deliveries.[2] Given the changes occurring in WECC, including the retirements of coal plants and other states establishing renewable portfolio standards, the Commission needs to identify realistic levels of both RA and energy imports and ensure that these accurate levels are reflected in the WECC-wide unit commitment and dispatch modeled in SERVM.[3] It is CalCCA's understanding that the SERVM model used by Energy Division in this proceeding does, in fact, already reflect significant

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2 *See ALJ Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions* (Ruling Seeking Comment), Nov. 6, 2019, at 16; *see also IRP Modeling Advisory Group Webinar: 2019-20 IRP Proposed Reference System Plan* (IRP Webinar), Nov. 6, 2019, at 29.

3 CalCCA has raised the need for a more detailed assessment numerous times. *See Opening Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues* at 13-15 (CalCCA Reply Comments); *see also Reply Comments of California Community Choice Association on Assigned Commissioner and Administrative Law Judge Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues* at 3-18 (CalCCA Opening Comments); *Comments of California Community Choice Association on Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (CalCCA PD Comments) at 3-6; *Amended Reply Comments of California Community Choice Association on Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* (CalCCA PD Reply Comments) at 2-3.

WECC-wide resource retirements, so artificial constraints on imports should not be needed unless expected retirements change. If, however, a need for 2,000 MW of generic resources exists, the Commission must identify resource- and location-specific solutions (*e.g.*, longer duration batteries) rather than assuming a lump sum of effective capacity. Providing greater clarity of what resources are needed, when, and where will give the state's LSEs far greater direction in developing those resources. Failing to do so will almost certainly result in a transmission grid that will not meet the needs of the energy portfolio.[4]

To target effective solutions requires *more accurate busbar mapping.* The Ruling proposes to have the busbar mapping process proceed on a parallel path with the adoption of the RSP. The busbar mapping process needs to improve in three primary areas to be better integrate into the IRP process.

- More frequent data and information sharing among the Commission, CEC and the CAISO is necessary to establish a more effective and timely feedback loop within the same planning cycle.
- Stakeholders need to have an opportunity to provide meaningful feedback into the busbar mapping process rather than having the decisions made administratively.
- The Commission needs to utilize the most updated information available from the CEC and CAISO assessments into the busbar mapping process as it becomes available. CalCCA has included some examples of such assessments in its response to Q. 12, Q. 19 and Q.20.

CalCCA has also offered informal comments on busbar mapping and looks forward to providing further input to improve the IRP outcome.

Finally, *the need to accommodate LSE-specific plans* into a systemwide planning exercise indisputably adds a layer of complexity, but one which has the potential to increase the accuracy

[4] *See Notice of Ex Parte Communication by the California Independent System Operator Corporation* (CAISO Ex Parte), Nov. 27, 2019, located at http://www.caiso.com/Documents/Nov27-2019-Notice-ExParteCommunication-IntegratedResourcePlanning-R16-02-007.pdf.

and reliability of the IRP outcome. Advances in IRP modeling and the learning afforded all stakeholders in the last IRP cycle will enable better alignment of the RSP and the plans of individual LSEs. Full alignment may be unrealistic, however; the least-cost, best-fit resources for individual CCAs may deviate from the RSP due to differences in anticipated demand profiles, existing portfolios, local environmental and economic development preferences, or other factors. Full alignment may also be undesirable as many LSEs have more aggressive decarbonization targets than statewide goals—the Commission should not hold back those LSEs innovating faster and should not take statewide goals as a ceiling rather than a floor. Understanding and modeling these differences offers an opportunity to advance the accuracy of the IRP outcome and may stimulate a greater range of possible solutions. The Commission should provide greater flexibility in the aggregation process for the 2020 Preferred System Portfolio and accommodate LSE-specific conditions where reasonable, requiring qualitative and quantitative support from LSEs presenting deviations.

The Commission, the IOUs, ESPs and CCAs share common objectives: maximizing the pace of decarbonization while maintaining system reliability. Aware of the challenges, and committed to fact-based and collaborative assessment, CalCCA looks forward to working with the Commission and other stakeholders to advance these objectives.

A. The IRP Process Should Avoid the Need for Urgent and Unanticipated Procurement Directives

The Assigned Commissioner and Administrative Law Judge issued an unanticipated ruling on June 20, 2019, to address the perceived inadequacy of procurement to meet system RA requirements in 2021-2023.[5] The June 2019 Ruling was issued less than two months after the

[5] *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues,* June 20, 2019 (June 2019 Ruling).

decision adopting the PSP for the 2017-2018 IRP cycle, which included four study years: 2018, 2022, 2026 and 2030.[6] Moreover, rather than relying on the IRP models—RESOLVE and SERVM—Energy Division Staff signaled the need for additional procurement relying on a "stack" analysis, which compared an inventory of available resources to the IEPR demand forecast.[7]

The Commission appears to have addressed obvious causes of the unexpected procurement track directive in this IRP cycle. One explanation could lie in the focus of the IRP on meeting carbon reduction goals, as required by Senate Bill 350, rather than specifically to ensure reliability. Another potential driver was the limited scope of LOLE analysis, conducted only for 2030 but not for 2022 and 2026—the other study years.[8] This shortcoming has been addressed fully in the 2019-2020 cycle. The treatment of imports also created a gap. Staff's stack analysis assumed only around 5 GW of imports, while the PSP assumed approximately 11 GW. Additional imports beyond 5 GW might be plausible and realistic, as discussed in response to Questions 8 and 9, and the Commission should coordinate with entities external to the CAISO balancing authority area to obtain a better estimate of the underlying loads and resources that will affect available imports in the future. Finally, the devalued ELCC for solar and wind resources also contributed to the shift between the 2017-2018 IRP and the procurement track directive. The underlying drivers of this ELCC shift (primarily shifting evening peak) are captured explicitly in the SERVM analysis that is now performed for interim model years.

The Commission should take direct aim at ensuring that the IRP prevents unanticipated, urgent directives in the future, thereby enabling LSEs to undertake a thoughtful and deliberate

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6 Decision (D.) 19-04-040 at 19.

7 June 2019 Ruling at 7-13.

8 *Decision Requiring Electric System Reliability Procurement for 2021-2023,* Rulemaking (R.) 16-02-007, Sept. 12, 2019, at 13-14.

procurement strategy. The Commission should seek comments from LSEs and other affected parties to identify any additional drivers for the procurement track to avoid creating similar conditions in the 2019-2020 IRP cycle. CalCCA looks forward to working productively with the Commission to develop approaches to ensure orderly planning in the future.

II. RESPONSES TO QUESTIONS POSED BY RULING

A. Modeling and Analysis

1. Please provide any comments on the use of the RESOLVE model.

RESOLVE is a capacity expansion model that co-optimizes investment and dispatch for a selected set of days of a multi-year horizon, in order to identify least-cost portfolios for meeting specified greenhouse gas targets. RESOLVE has been effective in providing a very high-level assessment of identifying resource mix in the outer years based upon meeting the economic and climate change policy objectives. The tool's availability in the public domain allows stakeholders to perform their own independent analyses that can be compared with the CPUC staff modeling efforts. As the market evolves, however, changes must be considered.

CalCCA appreciates Staff's efforts to improve the RESOLVE methodology, refine input assumptions, and calibrate the RESOLVE model with SERVM. In particular, CalCCA supports several refinements evidenced in the RSP:

- ✓ Updated levelized cost for different renewable and preferred resources including battery storage;
- ✓ New economic retention functionality to examine what portion of the existing gas-fired generation fleet should be retained or retired within the IRP planning horizon;
- ✓ Identification of procurement and type of renewable and integration resources including solar, battery storage, pumped storage, shed demand response and geothermal in a manner that can further minimize the need for retention of fossil resources;
- ✓ Allowing RESOLVE to build new transmission for 3 GW of out-of-state wind resources as a default assumption;

- ✓ Staff proposal on busbar mapping methodology for IRP portfolios includes stakeholder feedback opportunities to facilitate a better feedback loop between the CPUC IRP and CAISO TPP; and,
- ✓ Updated RESOLVE model that more fully represents "nested" transmission constraint limits and associated transmission costs.

Despite these refinements, RESOLVE continues to offer an incomplete representation in several respects. The model's representation of generation and transmission system has been simplified, preventing a full network understanding of procurement implications. In addition, it lacks adequate technological, temporal (*e.g.,* interday and seasonable energy needs) and geographical granularity for the resources it incorporates. These drawbacks create a level of uncertainty in the model outputs.

RESOLVE's effectiveness as a tool to advance decarbonization could be improved by incorporating additional configurations and attributes. To improve the model's flexibility and the suitability of its outputs, it should be modified to:

- ✓ Model multiple battery configurations and local solar options, particularly given the likelihood that hybrid solar/storage projects will be used increasingly to meet decarbonization goals;
- ✓ Incorporate criteria pollution considerations, recognizing their importance in addressing disadvantaged community concerns;
- ✓ Better incorporate in-front-of-the-meter distribution-connected resources as a distinct resource class with different cost characteristics than behind-the-meter resources; and,
- ✓ Include out-of-state wind transmission development.

These changes will enhance the output from RESOLVE, but may warrant some degree of additional model run time that may result from adding these attributes.

2. Provide any comments on the use of SERVM

The role of SERVM is to validate the reliability, operability, and emissions of resource portfolios generated by RESOLVE. SERVM is designed to inform security-constrained planning, meaning the primary objective is to reduce the risk of insufficient generation to an acceptable level. CalCCA appreciates Staff's efforts to improve the SERVM methodology, refine input assumptions and calibrate the model with RESOLVE. The model warrants further refinement, however, to improve the reliability of its output.

The SERVM model analyzes the capabilities of an electric system during a variety of conditions under thousands of different Scenarios and is thus better-suited than RESOLVE for system-reliability planning. Because it lacks transmission network representation, however, the model cannot capture the locational aspect of the effectiveness of generating resources. In particular, SERVM cannot capture the locational effectiveness of different types of generating resources in addressing local reliability needs. In addition, it fails to capture unit commitment constraints and transmission power flows.

Staff has improved the modeling process by calibrating RESOLVE and SERVM iteratively, by developing portfolios in RESOLVE, feeding the portfolios into SERVM, and then validating the key operational results, including GHG emissions, curtailment results, and dispatch patterns. This exercise has helped the stakeholders who do not have access to independently evaluate SERVM in vetting the output of RESOLVE and SERVM alike.

To improve the analytical process and usefulness of model output in the next cycle, CalCCA proposes that the Commission replace the model with a production cost model that models security constrained unit commitment and security constrained economic dispatch SCED. The commercially available production cost models that could be deployed include PLEXOS, GridView, UPLAN, GE MAPS, Power System Optimizer (PSO), AURORA, etc. If any of these models can be used in a parallel processing mode then it would be very helpful to run hundreds of scenarios in a timely fashion. Without these functionalities, it is impossible to determine location and effectiveness. Indeed, the CAISO uses SCUC and SCED to perform unit commitment and economic dispatch in its day-ahead market, hour ahead scheduling process, and real-time market. By updating the Commission's approach, IRP modeling will more closely align with the operations in the CAISO balancing authority area.

3. Provide any comments on baseline assumptions

The Integrated Resources Planning modeling relies on a set of baseline resources that can be predicted with relative confidence. The baseline includes:

- Existing resources, net of planned retirements;
- New resources that are sufficiently likely to be constructed, usually because they are owned by LSEs or contracted and have already been approved by the appropriate oversight body (*e.g.*, the Commission or a local governing board); and
- Projected demand-side programs that already have approved budgets under current policy, such as energy efficiency programs or net energy metering.

The baseline makes no further qualitative judgment on the availability of these resources.

While the baseline assumptions have been refined relative to the prior IRP cycle, several additional modifications would benefit future modeling. First, the baseline should reflect committed resources from non-IOU LSEs. CCAs have signed power purchase agreements for 3,386 MW of new build renewable and storage resources in California and throughout the WECC, the majority of which are not reflected in the baseline assumptions. CalCCA supports the development of a process for non-IOU LSEs to provide updates to the Commission as resources reach specific contracting and development milestones that could be incorporated through the development of the Reference System Portfolio.

Second, the Commission should expand coordination with other WECC-wide regulatory agencies to understand resource retirements and load forecasts to inform market interactions outside of CAISO and California. Like California, other regions are experiencing significant trends in their resource supply and demand, which, while uncertain, would be beneficial to further incorporate into IRP system modeling. These market interactions could inform new resource selection, fossil retention, the need for artificial import constraints, and other critical modeling considerations and results.

Third, the Commission should examine the assumption of 1,479 MW of 4-hour duration battery storage by 2030. Where the batteries are placed and their duration are two key dimensions critical to understand in establishing the baseline. Battery storage locations carry the potential to relieve local area constraints, and duration could affect the amount of capacity required. For instance, it appears that in some LCR areas and/or sub-areas, 4-hour storage is adequate, but in some other areas like SCE's Santa Clara sub-area, 8-hour storage might be required.[9] Presumably, if the need for 8-hour vs. 4-hour storage is known in advance, procurement contracts can be structured that comply with that need. For example, instead of stacking two 4-hour battery storage units it should be more effective to add an 8-hour battery storage in the Santa Clara area. The 4-hour battery duration is an artifact of past RA rules, but recent research by the CAISO has indicated that this is not sufficient to provide reliability within some local areas. Instead of treating storage duration as an input, the models should consider how to determine the appropriate duration of storage as discussed in response to Question 8.

Other issues have recently arisen with respect to the baseline assumptions underlying Decision (D.) 19-11-016 in comments submitted by stakeholders, including duplication of resources, inaccurate accounting for retirements and other technical issues.[10] To the extent the

[9] LCR Reduction Assessment Big Creek–Ventura Area and Santa Clara Sub-area, CAISO 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 12, located at http://www.caiso.com/Documents/Presentation-2019-2020TransmissionPlanningProcess-Nov182019.pdf.

[10] Parties submitted comments on baseline resources in R.16-02-007 on December 9, 2019.

same issues pervade the baseline resource assumptions for the RSP, changes adopted in response to recent comments.

4. Provide any comments on any other assumptions

Thermal Generation. In this new Reference System Portfolio analysis, RESOLVE allows retention of dispatchable thermal generation with the objective of minimizing the overall CAISO system costs, with the exception of planned retirements. In addition, thermal generation needed in local capacity areas is also assumed to be retained. CalCCA supports the new economic retention functionality in RESOLVE to allow a broader understanding of the potential use of these resources for renewable resource integration going forward. In addition, it appears that the CPUC has not yet performed the Thermal Retention Special Study, especially the low thermal retention study, which would assume 12.7 GW of thermal retirements by 2030.[11]

Beyond the current methodology, CalCCA supports inclusion of formal metrics for anticipated criteria pollution impacts of fossil resources classes as differentiated within the model, considering rate of criteria pollution (*e.g.,* grams per megawatt-hour), gross production of criteria pollution (*e.g.,* kilograms), and damage to human health in populated zones (*e.g.*, Disability Adjusted Life Years). While RESOLVE and SERVM's aggregation of generation facilities and geographical zones may blunt the specificity of these metrics, outputs from SERVM, such as hourly fossil demand within specific regions, could inform more detailed analysis which disaggregates fossil load and identifies specific operating units with known emissions characteristics and surrounding communities.

Renewable Resource Retirement. In addition to fossil resources, there is significant risk of the economic retirement of several thousand megawatts of existing renewable resources,

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[11] *Administrative Law Judge's Ruling Seeking Comment On Proposed Scenarios For 2019-2020 Reference System Portfolio*, R.16-02-007, Feb. 11, 2019.

primarily geothermal, wind, and biomass resources developed under PURPA. CalCCA encourages the expansion of the economic retention module to include consideration of these resources to assess their viability and fit with system need moving forward.

B. Scenario Results

1. Provide any comments on the scenarios and sensitivities modeled

In addition to the 46 MMT Default scenario, Staff has modeled two other major GHG target scenarios—38 MMT and 30 MMT—and a 2045 Case to capture Senate Bill (SB) 100 goals. In addition, a number of sensitivity cases were run, to test the impact of changes in assumptions for certain individual variables. These included the following sensitivity cases: no new OOS transmission, low-cost OOS transmission, high-cost OOS transmission, offshore wind, high solar photovoltaic cost, extension of the solar investment tax credit, high battery cost, paired battery cost, low resource adequacy imports, high resource adequacy imports, 2045 end year, a high-load sensitivity, full OTC extension, partial OTC extension, and early shed demand response availability. CalCCA recommends enhancements of the sensitivities included in the Commission's modeling efforts.

Additional sensitivities should be added to address battery storage duration. RESOLVE restricts the battery storage duration capability to four hours which the CAISO has indicated could result in deficiencies under certain circumstances and in certain local capacity areas.[12] As a reference case, CAISO analysis in the Moorpark Sub-Area Local Capacity Alternative Study indicates a mix of battery configurations would be needed in certain areas to cover both evening and overnight loads. While this does not suggest shorter duration battery configurations lack

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[12] *See* CAISO Moorpark Sub-Area Local Capacity Alternative Study, Aug. 16, 2017, located at https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

value, CalCCA suggests utilizing the IRP to identify an appropriate mix of battery configurations for system needs. CalCCA recommends that sensitivity scenarios recognize that at least a subset of battery storage capacity needs to have an 8- to 9-hour duration.

CalCCA ran a sensitivity scenario, attached as Exhibit A, that forced the baseline utility-scale FOM storage of about 1,479 MW by 2030 to all be 7-hour battery storage as a proxy for longer duration storage capacity. The scenario shows that assuming longer duration storage in the near term reduces the duration of needed incremental storage resources, especially in years 2022 and 2026.

Although RESOLVE does not provide any locational guidance for the longer duration Li-Ion battery storage capacity, the CAISO's annual transmission planning process provides high-level guidance in terms of duration requirement for a local resource needed to reliably and adequately address the local requirements within each of the LCR areas and sub-areas. Especially as new technologies better suited to longer durations and different cost dynamics become available (*e.g.,* flow batteries, flywheels, etc.), alternative battery technologies should also be modeled as distinct classes in RESOLVE. While the CAISO may not be able to perform as detailed analysis as they performed for the Moorpark Sub-Area,[13] a combination of the more detailed information provided under the annual Local Capacity Technical studies and the LCR Reduction studies performed under the CAISO's 2018-2019[14] and 2019-2020[15] Transmission

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13 *See CAISO Moorpark Sub-Area Local Capacity Alternative Study,* Aug. 16, 2017, located at https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

14 *Board-Approved CAISO 2018-2019 Transmission Plan*, March 29, 2019, located at http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf.

15 *Local Capacity Requirements Potential Reduction Study*, 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 111-213, located at http://www.caiso.com/Documents/Presentation-2019-2020TransmissionPlanningProcess-Nov182019.pdf.

Plans should provide LSEs much-needed guidance in procuring local resources that meet the various sub-area and area LCR requirements.

Modifying storage assumptions also affects other resources. It reduces the dispatch of CCGT units, reducing the need to retain gas-fired generation. In particular, by 2030, more than 400 MW of additional gas capacity is not retained in the longer duration battery storage case relative to the 46 MMT base case. The reduced reliance on the gas-fired generation is made up of a combination of increased duration of the battery storage dispatch and increased reliance on unspecified imports. The longer duration battery storage also reduces renewable curtailments as well as exports.

In order to show the true impact, storage resources need to be selectively modeled at appropriate locations in a production-cost model with unit commitment, economic dispatch, and a detailed transmission network. To the extent the Commission retains current modeling tools for the IRP, it may be worth developing an additional analytical process to identify and overlay localized storage needs which incorporates the system level storage needs identified in the IRP process.

2. Provide any comments on the common metrics compared across cases

When analyzing the various scenarios and sensitivities, Commission staff used a common set of metrics to compare results. These metrics included the selected candidate resources, the amount of thermal generation capacity not retained, costs (including a metric for incremental total resource costs, revenue requirements, and an average rate), and total GHG emissions.

CalCCA encourages the Commission to identify more direct metrics for success in the thermal generation fleet. While thermal generation capacity not retained may be a reasonable proxy, it is just that—a proxy for direct benefits in the form of reduced emissions (GHG and criteria) and reduced costs (fixed O&M). Rather than this indirect metric, the Commission should focus on reduced emissions from gas facilities in the aggregate for GHG and reduced operations of inefficient gas facility classes in densely populated regions for criteria pollution. Similarly, on a cost basis, Commission staff should focus on RESOLVE outputs of fixed O&M costs (the metric by which facilities are retained).

CalCCA recommends consideration of criteria pollutant levels as a metric. While GHG emissions get top billing in the RESOLVE analysis, criteria pollutant levels are critical from the local perspective. This metric can provide more information on the impacts of gas generation retention; retention of a simple cycle turbine will have materially different impacts than retention of a CCGT, and retention of a high capacity factor CCGT will have materially different impacts from retention of a low capacity factor unit. Finally, using criteria pollutants as a criterion also will help pinpoint impacts on disadvantaged communities, especially when combined with geographic screens to identify localized impacts of resource siting and retirement.[16]

3. Provide any comments on the results from the major scenarios or sensitivities analyzed by Commission staff to develop the RSP recommendation

CalCCA strongly supports the choice to model the 30 MMT and 38 MMT cases, along with the express examination of the potential of OOS resources to address affordability concerns with decarbonization. As many CCAs are more aggressively driving decarbonization within strict cost constraints, this examination of these scenarios is extremely useful for innovative LSEs seeking to deliver the state's goals sooner. CalCCA also recognizes that it appears not all of the scenarios scoped in the February 11, 2019, ruling were conducted, and urges the Commission to conduct those studies to inform California's strategies for decarbonization.

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[16] For an example of a methodology of combing capacity expansion modeling with geographic overlays, please see the work of The Nature Conservancy and E3 in analyzing the interaction between habitat conservation and renewable energy siting. Located at https://www.scienceforconservation.org/products/power-of-place

4. Comment on the modifications to SERVM made by Commission staff to approximate RESOLVE's PRM constraint, which limits the amount of imports that can count towards resource adequacy. Were the changes appropriate? Why or why not?

a. Response to Ruling

When Staff were preparing variations on assumptions to analyze the 46 MMT Default and Alternate Scenarios, they discovered an issue when comparing results from the RESOLVE and SERVM models. While both models include a simultaneous import constraint for the CAISO area at the maximum import capability level (approximately 11 GW), RESOLVE contains an additional constraint of 5 GW as the default assumption for imports that can be counted towards RA and meeting the planning reserve margin requirement of 15 percent. SERVM, by contrast, did not have any similar additional constraint on imports. Thus, in assessing whether the electric system was sufficiently reliable, SERVM was relying on a larger set of potential imports than RESOLVE. To further constrain SERVM to approximate RESOLVE's assumption that only 5 GW of imports can count towards resource adequacy, Staff have now added in SERVM a second CAISO simultaneous import limit of 5 GW that applies for all hours where gross electric demand is higher than the 95th percentile.

SERVM performs a WECC-wide hourly 8,760 chronological production costs analysis based on a detailed representation of loads, generation, and transmission infrastructure into the future. It is likely that when SERVM did not have this 5 GW of artificial constraint for economic dispatch purposes, it resulted in a level of additional import beyond 5 GW for some hours.

The import constraint, which is fixed throughout the modeling horizon, appears arbitrary and is inconsistent with the results of the SERVM modeling runs that reflected expected WECC-wide loads and resources. Import availability likely will tighten as coal plants retire—*conditions* *already taken into account in the SERVM model runs*. In addition, other western states will require increasing levels of balancing resources to integrate higher levels of renewables.[17] For example, while Washington is phasing out coal by 2025, Nevada's last coal plant may stay operational through 2025 or later, Oregon's coal ban takes effect in 2035, and other western states will do so later, if at all. Similarly, different states across the WECC may be implementing RPS standards in coming decades but at widely varying rates. IRP modeling must rely on something more than a general sense of these trends and an arbitrary 5,000 GW constraint, particularly when applied to energy as Staff has done.

Moreover, the 5,000 MW constraint does not reflect near-term and perhaps even mid-term realities. In 2019, imports have averaged around 6,000 MW, have exceeded 7,400 MW 25 percent of the time, and have reached slightly over 11,000 MW at their peak, as shown below.[18]

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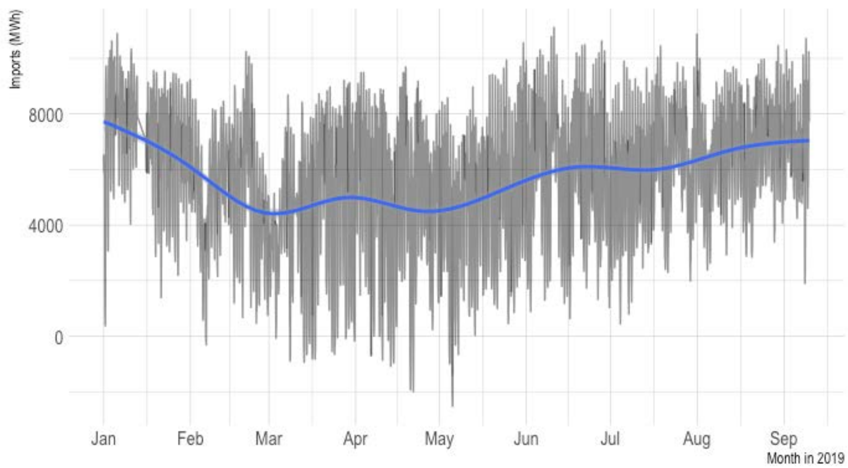
17 CalCCA is aware of a recent study released by Energy+Environmental Economics on behalf of Rye Development, a developer of low-impact hydropower and energy storage projects in the U.S., which addresses one piece of the import puzzle: *Capacity Needs of the Pacific Northwest – 2019 to 2030*, locatd at https://www.ethree.com/wp-content/uploads/2019/12/E3-PNW-Capacity-Need-FINAL-Dec-2019.pdf. The public summaries of the study, however, lack sufficient detail to fully understand how it was developed and how to interpret its conclusions. With its Northwest focus, the analysis excludes Powerex, BP Hydro, Nevada Energy and Arizona Public Service—critical pieces of the import puzzle.

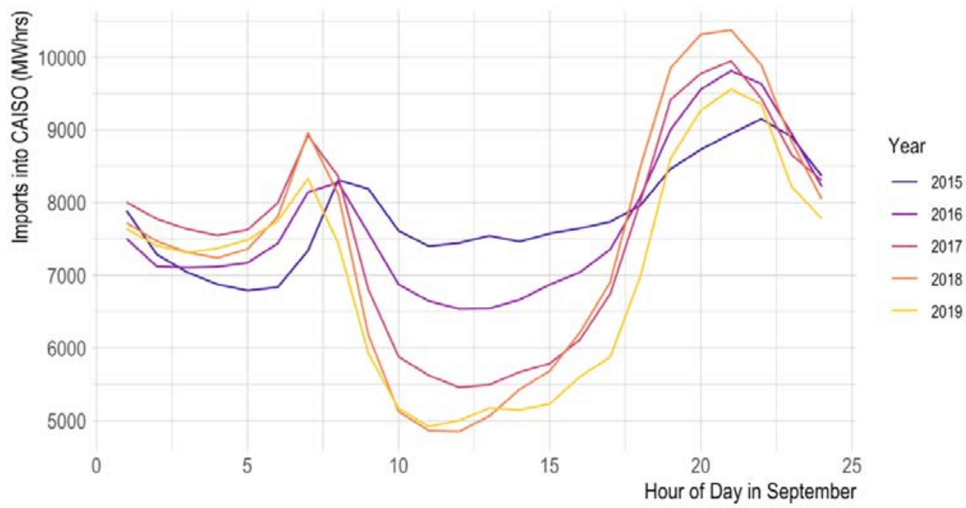
18 This conclusion is based on data from the Energy Information Administration's Form 930, which collects self-reported CAISO intertie net-exchanges into and out of the Balancing Authority. Located at https://www.eia.gov/todayinenergy/detail.php?id=27212

Figure 1: September 2019 Exports



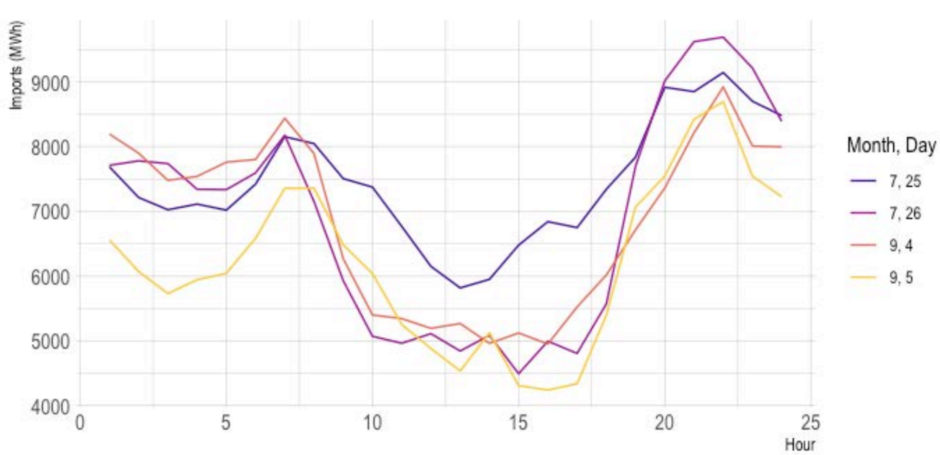
Notably, imports have been near their highest levels during September, the CAISO's 2019 peak month. The average level of imports in September was 7,583 MW, exceeding 8,668 MW 25 percent of the time and peaking at 11,113 MW. Particularly striking that import volumes in September over the past five years have tended to support the late afternoon ramp and were highest during peak and after peak hours (strongly resembling the duck curve).

Figure 2: September Imports 2015-2019



The pattern was similar for the four highest CAISO demand days in 2019, with peak imports hovering around 8,000 MW to 9,000 MW and dipping during the day when the sun shines, as shown below.

Figure 3: Imports 4 Highest CAISO Demand Days 2019



Thus, while Staff has reasonable grounds for its caution regarding import reliance, import availability should be studied more closely to assess the pace of anticipated decline before resorting to the blunt instrument of a 5,000 MW constraint for all study years. Until a study can be completed, the Commission should modify import availability sensitivities to utilize an import constraint trendline rather than a static value.

Ideally, the Commission would conduct a sensitivity analysis of imports and couple that with information from the WECC to determine the most likely trend. Given that differences in assumptions about imports drive nearly all the differences among estimates, the Commission should evaluate a range of import constraint levels, each with declining trends that reflect declining availability of existing capacity. In each of these cases, building new capacity is essentially a hedge against declining import availability. Additionally, the Commission should collect information in coordination with other entities throughout the WECC to determine the likelihood of each scenario. By modeling high, moderate, and low trends, combined with an evaluation of the likely constraint trends, the Commission should be in a position to evaluate meaningfully which scenario California should plan to hedge against.

In any event, greater coordination with planning and regulatory bodies throughout WECC to develop a more analytically robust import constraint, which considers both the shifting supply and demand throughout the planning horizon, will ensure a more accurate modeling of potential imports to California.

b. Response to Powerex

CalCCA appreciates that Powerex submitted its RSP comments on December 11, 2019, enabling a response in these comments. Powerex concludes:

> [T]he "default" and "high" assumptions related to RA imports significantly overstate the quantities of forward capacity that will remain available for contracting in the month-ahead and year-ahead System RA procurement timelines.[19]

It further concludes that the "low" scenario for RA imports of 2,000 MW is reasonable and that the "default" scenario of 5,000 MW of RA imports overstates available capacity.[20] Powerex recommends that the Commission thus "revise the 'default' scenario to include the 2,000 MW of existing long-term contractual entitlements from the 'low' scenario, plus an estimated 1,000 MW of RA imports that can be procured on a year-ahead basis, for total "default" RA imports of 3,000 MW." Powerex's analysis curiously distorts the role imports play in meeting California energy needs.

Adopting Powerex's proposal would ignore the huge amount of available import capacity and the load/resource balance of the entire WECC. Critically, Powerex fails to note that the Staff's SERVM runs modeled the fossil generation retirements included in its table. The SERVM runs used in this proceeding thus have *already* captured the tightening supply conditions in the West that Powerex describes.

In addition, Powerex highlights that "during high load conditions across the West, when short-term market prices are elevated, the CAISO BAA is often only able to secure as little as 4,000 MW of import deliveries," focusing on summer periods of 2017 and 2018. This overlooks the fact that imports were low at the time of the 2018 peak because solar and wind production was high and internal gas-fired resources were less expensive than the incremental imports. Thus, the story is not that only 4,100 MW were *available* during those periods; to the contrary, only 4,100 MW of imports were *needed* for those intervals. The chart below shows that by 7

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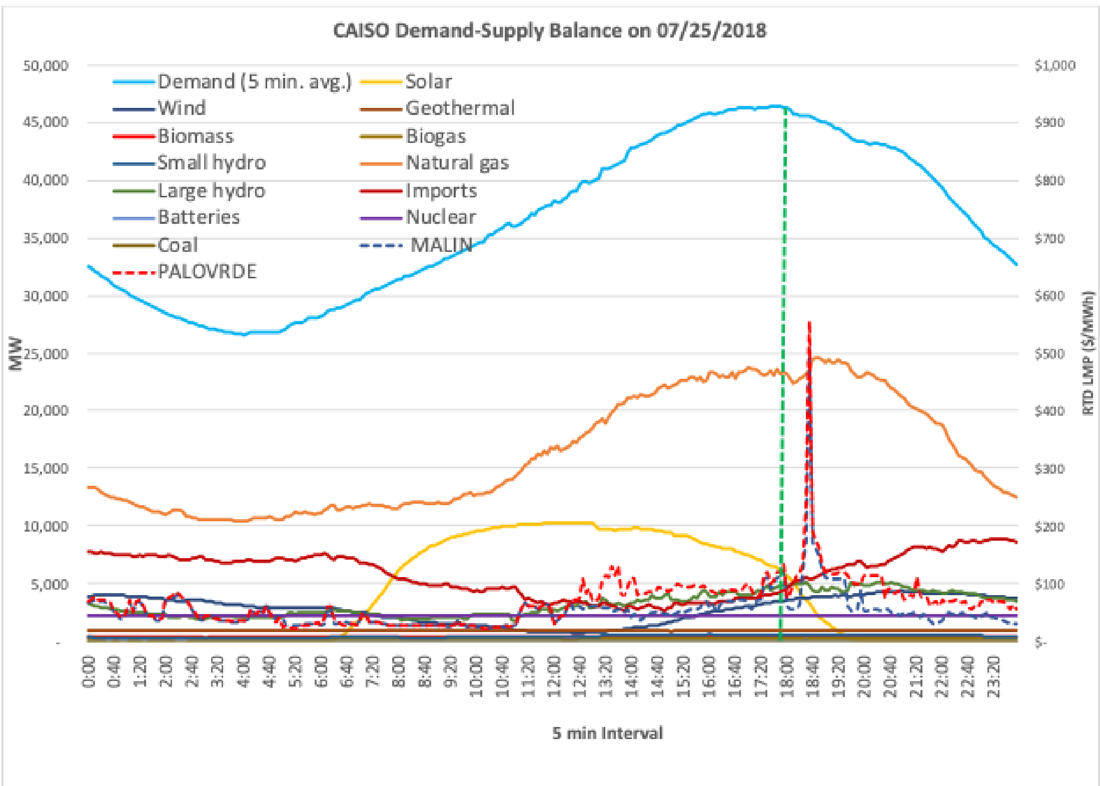
[19] *Comments of Powerex Corp. on Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portolio* [sic] *and Related Policy Actions*, Dec. 11, 2019, at 1.

[20] *Id.* at 2.

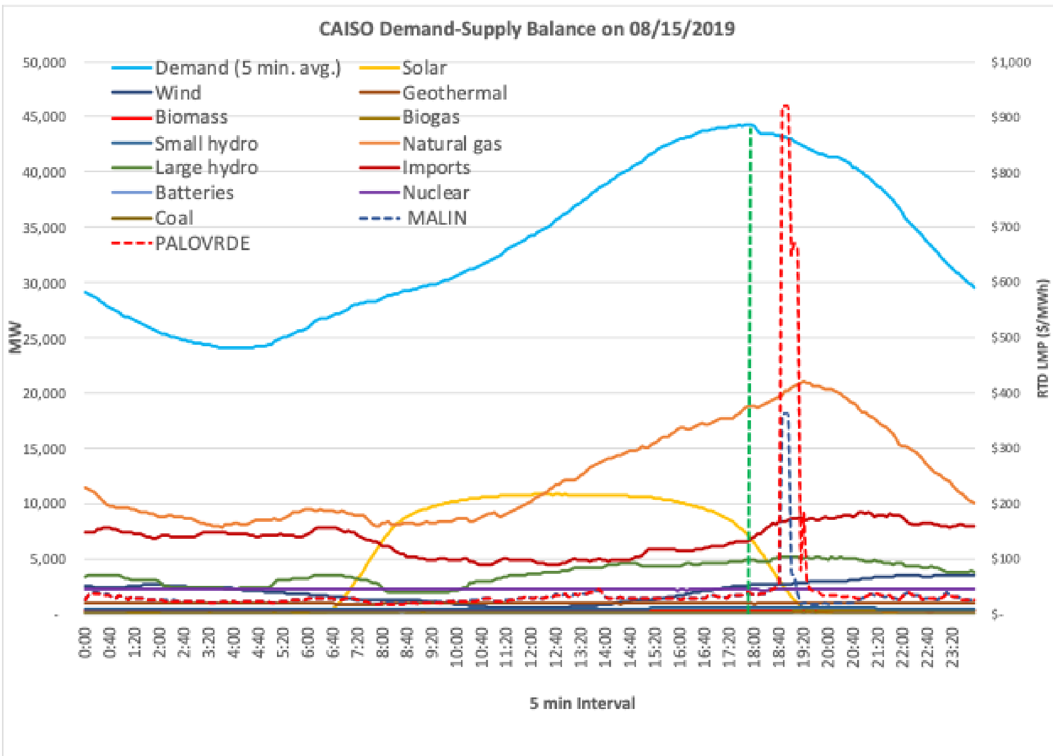
p.m., imports were above 6,000 MW; by 9 p.m., they were 7,600 MW; and at 11:25 p.m., they peaked at 8,941 MW. Powerex attributes reductions in imports to elevated prices in the West, the figure below contradicts their theory. The Palo Verde and Malin price spikes in the middle of the day and after the peak hour, did not materially change the levels of imports before and after the spikes.

Figure 4: CAISO Demand - Supply Balance, July 26, 2019



A similar pattern was observed during the 2019 peak day of August 15, 2019, but in this case, imports happened to be at 6,784 MW during the peak hour (much greater than the peak day in 2018), rising to 8,621 MW at 7 p.m., and a high of 9,189 MW at 9 p.m. The "trend" of reduced peak imports suggested by Powerex, would appear to have reversed itself in 2019. While there was a similar price spike during the evening ramp in 2019, it also did not materially affect the level of imports. Instead, as during the 2018 peak day (and most days), imports were lower during the high solar production hours and higher during the low solar production hours, as discussed in part a. This does not mean the imports could not have served more load if needed during different hours, it just means the efficient CAISO dispatch took the imports when it made sense to do so. See the attached spreadsheets for the underlying data.

Figure 6: CAISO Demand-Supply Balance, August 15, 2019



CalCCA appreciates Powerex's efforts to progress the import discussion and looks forward to further discussions with Staff and stakeholders to get a more workable view of import availability over the planning horizons.

5. Comment on the manual addition of 2,000 MW of "generic effective capacity" in order to produce a portfolio with an LOLE result of less than 0.1. Would you recommend a different way of depicting the reliability gap in the portfolio? If so, describe in detail.

To ensure SERVM simulations that would demonstrate a 0.1 loss of load expectation or better level of reliability for the 46 MMT Alternate Scenario, Staff estimated that 2,000 MW of generic effective capacity would need to be added to the portfolio. The 2,000 MW were added to the study years of 2026 and 2030, meaning it would be online by 2026. No extra capacity was added in 2022, since the 46 MMT Alternate Scenario included a partial extension of existing OTC units that should provide sufficient effective capacity in 2022.

Resolving the discrepancies across SERVM and RESOLVE takes time, presenting challenges in this IRP cycle. It is reasonable that SERVM, a more granular model with more constraints than RESOLVE, would identify a point of failure not identified in RESOLVE—in fact, this is the design and intent of the two model setup, and a certain degree of misalignment between the models should be expected. However, CalCCA encourages staff and stakeholders to better understand why the models fail to align in 2026 and explore resource solutions which best fit the identified gap.

Specifically, Staff's selection of generic capacity in the form of a zero-emission peaking facility does not give sufficient insight into the kinds of resource solutions that will occur in 2026 following the retirement of Diablo Canyon. As noted by Staff, this gap could realistically be met by several resource types—firm imports, battery storage, renewable resources, demand-side management, or thermal generation. It is important that the Commission identify specific resources so that the CAISO's Transmission Planning Process can ensure that the needed transmission can be added to ensure that the resources and energy can be used. The CAISO emphasized this in its *ex parte* notice filed November 27, 2019.[21]

SERVM runs with specified resources in-lieu of the generic capacity will serve two critical purposes. First, these runs will help identify which least-cost, preferred resources or resource characteristics could best meet the 2,000 MW shortfall. Second, they will help

[21] *See* CAISO Ex Parte.

determine whether 2,000 MW is in fact the correct capacity to meet the 0.1 LOLE constraint. The potential impact on ratepayers of getting it wrong is significant: 2,000 MW of generic capacity need met by battery storage ultimately lacking the requisite characteristics would impose an unnecessary cost on ratepayers of roughly $8/kW-month (nearly $200 million annually).

C. Electric Sector GHG Target

1. Do you support the 46 MMT Alternate Scenario as the basis for the GHG emissions goal for 2030 to be affirmed by the Commission? Why or why not? If you propose a different scenario, explain your rationale.

The primary assumption changes in the 46 MMT Alternate Scenario, relative to the 38 MMT and 30 MMT scenarios, are related to OTC unit retirements, the deployment of storage, the pace of solar buildout, and potentially greater reliance on new OOS renewable resources. While CalCCA does not oppose the 46 MMT Alternate Scenario's assumptions regarding limited near-term solar resource development and partial OTC (2,289 MW) extension, many CCAs have local requirements that exceed the state's goals and are planning for 30 MMT scenarios or even greater reductions. As discussed above, however, the 5,000 MW import constraint, which likely drives the need for 2,000 MW of generic capacity, appears arbitrary and overly conservative, devaluing the significant investments on the part of California ratepayers in transmission to supply sources across WECC. To the extent the Commission adopts the RSP with generic capacity, it should understand that planning years containing generic capacity (2026 and beyond) require further analysis and vetting before they can be considered meaningful, let alone binding, direction for LSE procurement.

D. Electric Resource Portfolio

1. Are you concerned about the risk of overreliance on solar as part of the recommended portfolio? Why or why not?

The RSP does not present a risk of overreliance on solar resources in the near- or mid-term. The utility-scale solar capacity required to meet policy goals also represents almost a doubling of solar capacity compared to current in-state solar in California. Similarly, the battery capacity selected for this portfolio is approximately 10 GW, which is roughly ten times the installed capacity of batteries nationally in 2018. As CalCCA pointed out in Section I, however, assessment of portfolio needs turns on the planning horizon underlying the question. All signs, today, point to increasing reliance on solar resources as a good strategy.

As the grid and technologies evolve, however, so will California's view of solar, and course correction will be necessary. It is important to keep in mind that California's initial two decades of RPS implementation faced the same degree of anxiety and skepticism, yet the goals have been achieved. The achievement has not been a product of luck, but of planning, innovation, and continued refinement throughout the process. The next decade of California's renewable transition can be achieved through a similar process, as suggested by the wide range of regulatory[22] and industry[23] planning indicating that high solar and storage penetration are feasible, reliable, and cost-effective, particularly when paired with complementary resources such as OOS and offshore wind.

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[22] CEC / E3 Deep Decarbonization in a High Renewables Future, located at https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

[23] Southern California Edison, Pathway 2045; November 2019, located at https://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/201910/201911-pathway-to-2045-white-paper.pdf.

2. Are you concerned about the risk of overreliance on battery storage as part of the recommended portfolio? Why or why not?

The RSP does not present a risk of overreliance on battery storage in the near- or mid-term. The portfolio is not, however, without uncertainty:

- With only 833 MW of battery storage expected to be online by 2020, battery storage is untested at high levels of penetration in California as in other regions;
- The battery capacity selected for this portfolio is approximately 10 GW, which is roughly ten times the installed capacity of batteries nationally in 2018;
- As noted earlier, the RSP may be overly reliant on 4-hour batteries, and additional sensitivities are required to test battery storage of longer duration. Despite these uncertainties, battery storage continues to be a good strategy;
- Given the nature of the storage, location is critical, and there is a need to increase the granularity in identifying the location of storage to ensure its effectiveness; and,
- The pace of technological change all but ensures that new technologies will play an increasing role.

This uncertainty highlights the need for the Commission to avoid procurement directives that order premature storage deployment, because such an approach may prevent deliberate procurement strategies, prevent California from taking full advantages of technological advances, and saddle customers with unnecessary stranded costs.

Developer and LSE incentives are driving configurations and contracting structures that support utilization of battery storage as envisioned in SERVM and other planning exercises. CalCCA encourages the Commission and stakeholders to observe and test battery viability in this and subsequent IRP cycles, with opportunities in the 2021-2022 IRP to refine and correct storage assumptions in line with the tested experience. While battery reliability and degradation are potential areas of performance risk, innovation in controls, chemistry, and other areas are likely to mitigate performance risk on these fronts in coming years.

The 2019 IRP renewable resource portfolios currently under development for the 2020-2021 TPP need to identify the locations of the storage capacity with some degree of granularity. The 2017 IRP portfolio entailed approximately 2,000 MW of Li-Ion battery as the Commission CPUC did not identify their general locations. The 2019 IRP portfolios are expected to have more than 11,000MW of Li-Ion battery storage capacity by 2030.[24] Therefore, the Commission, in coordination with the CEC and the CAISO, needs to play a key role in identifying appropriate locations and types of storage resources. CalCCA believes that the Flexible Capacity Deliverability studies and LCR Economic Assessments performed by the CAISO in the current TPP and 2018-2019 TPP are very useful in identifying the location and attributes of storage resources. In particular, the Flexible Capacity Deliverability Assessment performed by the CAISO in the 2019-2020 TPP[25] could provide a good guideline for the CPUC in locating the selected 2019 IRP storage resources in different *generation pockets*.

Similarly, the CAISO's LCR Economic Assessments should inform the amount of battery storage that could be located in the various *load pockets*. These studies are also very informative in identifying the attributes of the required storage resources. Additionally, the Commission should provide guidance on defining an adequate amount of utility-side (front-of-the-meter) solar resources that could be co-located in local areas or sub-areas to ensure that there is adequate generation available to charge the battery storage.

The Commission should review and revise regulatory structures that may limit LSE investment in hybrid and standalone storage, such as uncertainty in accounting and future ELCC revisions for storage. In particular, CalCCA encourages the Commission to adopt a vintaging

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[24] CPUC Energy Division, *2019-20 IRP: Proposed Reference System Portfolio Validation with SERVM Reliability and Production Cost Modeling*, Nov. 6, 2019, at 17.

[25] *Flexible Capacity Deliverability Assessment*, 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 20-29.

methodology for battery storage and other resources that face ELCC derating due to saturation, which today represents a significant barrier for LSEs to pursue long-term storage investments that rely on resource adequacy value as a significant revenue stream.

Finally, the Commission should focus on improving the strategic location of storage resources to address local capacity requirements by increasing the accuracy of and utilizing the busbar mapping. The efforts to improve effectiveness through location should, moving forward, align with resilience efforts to mitigate reliability impacts from Public Safety Power Shutoffs and other public safety emergencies.

3. Is the retention of most or all of the current thermal generation fleet reasonable and realistic? Why or why not?

As indicated in response to Question 6, approaching the question of retention of thermal generation as a binary choice oversimplifies the issue. Criteria pollutant emissions levels, which depend upon technology and capacity factors, and resource location add granularity to the analysis that will better enable the Commission to determine whether thermal generation retention is "reasonable and realistic." In addition, CalCCA supports conducting the thermal retention special study to specifically examine the costs associated with greater or slower thermal retirements. Throughout, these costs must be evaluated compared to the accelerating costs climate change is imposing on California through drought, wildfires, changing hydrological regimes, and sea level rise.

Without consideration of these factors, RESOLVE chooses not to economically retain approximately 3.7 GW of the existing thermal generation in 2030, leaving 21 GW in operation. Retention of some amount of thermal generation may be appropriate until alternative technologies can be deployed to reduce the reliance on thermal generation without impairing reliability. Such solutions may include a hybrid electric gas turbine that combines the storage resources with gas plants, which would potentially allow for a smaller fleet of gas resources while a fully decarbonized grid is deployed.

4. Do you have additional comments about the portfolio associated with the 46 MMT Alternate Scenario?

CalCCA has no comment at this time, but notes that many CCAs are under local carbon reduction requirements that are more rigorous.

E. Commission or LSE Actions in Response to Portfolio Recommendation

1. Should the Commission take steps to begin development of transmission and/or generation from geothermal resource areas? If so, what steps? If not, why not?

As a preliminary matter, CalCCA questions whether these comments are the appropriate place to ask this question. Whether or not the expense of additional transmission and generation in geothermal areas is warranted depends in large part upon the portfolios presented by LSEs and the suitability of the portfolios to achieving decarbonization and reliability goals. These comments should appropriately focus on modeling and portfolio development.

With this reservation, some resources, including baseload renewables (geothermal and biomass) and alternative storage (pumped hydro) present distinct and, at times, complementary attributes to the growing fleet of solar, wind, and battery storage resources. However, there is little evidence within the proceeding record which supports the significant above-market investments in both generation capacity and transmission capacity required to develop these resources at a significant scale. Although no geothermal specific special study was scoped in the RSP analysis in the February 11, 2019, ruling, this question may be appropriate for further analysis. That said, refined modeling within the 2019-2020 modeling cycle, with improved cost assumptions, does not expect new build geothermal to be a part of the resource mix through 2030 outside of specific sensitivity cases.

A number of stakeholders have expressed concerns regarding the inequity faced by developers of certain renewable resources which have been overlooked by LSEs and planning exercises seeking least-cost, best-fit resources. In particular, these renewable resources represent one approach to addressing periods of persistent low generation from solar and wind, although other approaches, such as regional integration may also address such concerns. Despite the unique benefits offered by these resources, these benefits may not outweigh the significant costs associated with these resources relative to other, more cost-effective technologies which provide similar benefits. Ultimately, the Commission should consider additional studies of such conditions and the loss of load expectations associate with these functionalities.

The Commission should be cautious not to burden ratepayers with unnecessary above-market costs in order to address inequities between groups of corporate developers of renewable projects with unfavorable economics. California should keep its sights set on decarbonization and reliability, rather than choosing technology winners and losers absent compelling cost-benefit analyses.

2. Should the Commission take steps to support the development of at least one pumped storage facility in California? If so, what steps? If not, why not?

Again, CalCCA observes that this question may be more appropriately addressed after LSEs have provided their individual IRPs; the purpose of the inquiry in these comments should be limited to the development of the RSP. RESOLVE includes only 85 MW of pumped storage. The resource comes online in 2026, and it is built under only the most stringent—30 MMT—GHG target. In light of these circumstances, no pumped storage should be considered in the medium term at this time.

Whether or not pumped storage is included in the RESOLVE model, however, does not prejudge procurement of these resources. While the Commission suggests that the capitalintensive nature of pumped hydro could act as a barrier to individual LSEs investing in the resource, CCAs already can and do coordinate to procure larger projects. For example, a collaborative effort between Monterey Bay Community Power and Silicon Valley Clean Energy procured what was California's largest solar and storage facility at the time.[26] CalCCA members are currently exploring building on this multi-CCA model to pursue even larger needed projects to address our collective local requirements. Among these, CalCCA members are investigating pumped storage projects and will pursue this option if cost-effective development opportunities arise.

3. Are there other actions the Commission should take specifically with respect to replacement capacity for the Diablo Canyon nuclear plant? Describe in detail.

CalCCA encourages the Commission to pursue further modeling and analysis related to the Diablo Canyon Power Plant closure. While the IRP models incorporate high-level planning around the DCPP closure, the significant supply shock associated with DCPP's retirement may warrant further, more granular analysis to ensure resource sufficiency in 2025 and beyond. Specifically, the generic resource build results from the RESOLVE process should be incorporated into a more sophisticated, more granular model that can confirm system reliability. As noted elsewhere, the 2,000 MW generic capacity stop-gap incorporated into SERVM to address the 2026 model year gap indicates that further analysis is needed. This further modeling, together with collective action developed through the IRP process, will ensure a successful retirement of California's last nuclear power plant.

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[26] Located at https://www.prnewswire.com/news-releases/largest-california-solar-plus-storage-project-agreement-signed-between-canadian-solar-subsidiary-recurrent-energy-silicon-valley-clean-energy-and-monterey-bay-community-power-300740151.html

Decommissioning of DCPP will require resource replacement to shore up system reliability. As the Commission recently directed in D.19-11-016, any *system* RA deficiency created by DCPP retirement should allocated to all LSEs within the three IOU TAC areas based on their load ratio share. To enable this determination, SERVM should isolate DCPP impacts on reliability needs using a "DCPP in/out" methodology.

4. Are there other actions the Commission should take with respect to development of any other types of capacity or resources such as offshore or out-of-state wind? Describe in detail.

At least two CCAs have begun to explore offshore wind opportunities, and CalCCA suggests examining the integration of these resources in the 2026 and 2030 scenarios. Offshore wind represents a new and promising resource for California which complements the generation profiles of both on-shore wind and solar and thus could prove to be a critical renewable integration strategy.

CalCCA appreciates the Staff's new modeling that allowed RESOLVE to build new transmission for 3 GW of OOS wind resources as a default assumption. Although the 46 MMT case did not select any OOS wind resource dependent on new transmission, the more stringent GHG targets, such as 38 MMT and 30 MMT, select highly significant amounts of OOS wind.[27] It is also important to note that the OOS wind resources are cost-effective under 30 MMT target, even under higher transmission cost assumptions. Overall, the Staff's updated analysis suggests that the OOS wind resources need to part of the future portfolios, even taking into account cost of new transmission infrastructure.

Indeed, California CCAs may find development of resources outside of California to be an effective strategy for addressing affordability concerns around decarbonization if those

[27] Ruling Seeking Comment, Attachment A (2019-20 IRP: Proposed Reference System Plan), slides #98-99.

resources prove to be more cost effective. Critically, the transmission and out-of-state wind sensitivity analyses suggest that increased reliance on new transmission to cost-effective out-of-state wind could save Californians hundreds of millions or billions of dollars annually, depending on the costs of transmission, although at least 5 GW of out-of-state wind is selected in all cases at the 30MMT scenario.[28] For those LSEs that are moving faster toward the state's goals, these cost considerations will be significant in designing portfolio plans. While CalCCA is mindful of objectives around local economic activity, at a time when high and climbing electricity rates are already a matter of grave concern for many communities, the Commission should support efforts to rely on such new resources for both energy and RA capacity.

F. CAISO TPP Recommendations

1. Comment on the recommendation to use the 46 MMT Alternate Scenario as the reliability and policy-driven base cases for the next CAISO TPP.

The CAISO uses the reliability and policy-driven IRP base cases to identify transmission upgrades needed that, once identified, will proceed directly to the planning stage and be brought to the CAISO board for consideration. The base case recommended for this purpose is the 46 MMT Alternate Scenario.

CalCCA supports the 46 MMT Alternate Scenario for reliability and policy-driven bases cases. This support, however, is contingent on a robust feedback loop between the IRP and CAISO TPP that includes stakeholder feedback on the busbar mapping process. In addition, as noted in response to Question 5, however, the CAISO requires greater specificity in the 2,000 MW generic effective capacity addition, and the RSP should be further refined to address this shortfall prior to its adoption and transmission to CAISO for purposes of transmission planning.

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[28] CPUC Energy Division Presentation "2019-2020 Preliminary IRP results," Oct. 4, 2019, at 87 and following.

In the CAISO's *Ex Parte* discussed earlier the CAISO suggested three possible methods for correcting this problem.[29] CalCCA encourages the Energy Division to work with the CAISO to find an acceptable method to ensure that the TPP accurate models the expected portfolio.

2. Comment on the recommendations for policy-driven sensitivities around curtailment in particular transmission zones and the associated impact on EO or full deliverability for renewables.

The CAISO provides the transmission capability limits and upgrades cost estimates used as a direct input into RESOLVE for the IRP analyses to ED staff annually. Currently, if a transmission zone does not have dispatchable resources, the CAISO assumes a 20 percent exceedance level of curtailment of new resources would be possible during summer peak load conditions, based on the current on-peak deliverability methodology, but does not provide an energy-only capability number. A zero EO limit is assumed for those areas in RESOLVE. The Staff has proposed to collaborate with the CAISO staff during the 2020-2021 TPP cycle to incorporate less stringent EO limits than estimated in the past. The Staff has proposed two different approaches comprising new EO limits incorporated into RESOLVE allow the model to build new generation in more transmission zones.

These updated EO limits would be developed under the assumption that an increased amount of curtailment would be permitted in various transmission zones. In particular, the current proposal is to have a *Policy-Driven Sensitivity 1*, which includes LEVEL 1 updated EO transmission capability estimates by expanding the EO transmission capability estimates for zones, which had capabilities previously marked as TBD or which required minor upgrades to accommodate EO resources. The *Policy-Driven Sensitivity 2*, in addition to LEVEL 1 estimates, LEVEL 2 will increase the EO transmission capability estimates for zones with relatively low-

[29] CAISO Ex Parte.

cost upgrades by the same amount as the incremental capability provided by the corresponding upgrade. CalCCA is not opposed to selecting one out of the two suggested policy-driven sensitivities with a preference towards the *Policy-Driven Sensitivity 1* as the EO estimates therein do not rely on any new additional transmission upgrades.

Instead of the proposed *Policy-Driven Sensitivity 2*, CalCCA recommends that the Staff utilize a portfolio that is based upon the transmission capability estimates reflecting CAISO's revised deliverability methodology.[30] The implementation of the revised methodology would result in accommodating more full capacity deliverability status resources in a given transmission area than under the existing methodology without triggering the need for additional transmission upgrades. The CAISO has found that several upgrades identified using the current methodology would not be needed under the new methodology. Since the CAISO, in its 2020-2021 TPP, is expected to deploy its revised deliverability assessment for the policy-driven assessment, it is appropriate to provide at least one sensitivity portfolio, if not the base portfolio itself, that is based on the consistent set of assumptions.

3. Comment on the suggested process for seeking formal input on busbar mapping of the proposed RSP.

The mapping process being conducted by the CEC and Commission staff—a valuable contribution to identifying key locations for resource deployment—is not yet complete. To provide a more efficient process, while also allowing formal input from parties on the mapping process, this ruling proposes to have the busbar mapping process proceed on a parallel path with the adoption of the RSP. To facilitate this, a separate ruling will be issued in the near future with details of the busbar mapping and seek party comments on the methodology and the results.

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[30] For more details on this proposal, see the CalCCA's July 19, 2019 comments on the June 17, 2019 workshop and the Unified RA and IRP Modeling Databases released June 28, 2019 and revised July 15, 2019, at 5-6.

The 2019 IRP renewable resource portfolios currently under development for the 2020-2021 TPP need to identify the locations of renewable capacity, in general, and storage, in particular, with some degree of granularity. The 2017 IRP portfolio utilized in the 2019-2020 TPP entailed approximately 2,000 MW of Li-Ion battery. However, the CAISO did not model them in the 2019-2020 TPP studies at all as the ED did not identify their locations. The 2019 IRP portfolios are expected to have more than 10,000 MW of Li-Ion battery storage capacity by 2030.[31] Therefore, the Commission, in coordination with the CEC and the CAISO, needs to play a key role in identifying appropriate locations and types of storage resources. CalCCA believes that the *Flexible Capacity Deliverability* studies and the LCR Economic Assessments performed by the CAISO in the current TPP and 2018-2019 TPP are very useful in identifying the location and attributes of storage resources. In particular, the *Flexible Capacity Deliverability Assessment*[32] performed by the CAISO in the 2019-2020 TPP could provide a good guideline for the CPUC in locating the selected 2019 IRP storage resources in different generation pockets.

Similarly, the CAISO's *Local Capacity Requirements (LCR) Economic Assessments* should inform the amount of battery storage that could be located in the various load pockets. The *LCR Economic Assessment* studies are also very informative in identifying the attributes of the required storage resources. These studies are also very informative in identifying the attributes of the required storage resources. Additionally, the Staff should provide guidance on defining an adequate amount of utility-side solar resources that could be co-located in local areas or sub-areas to ensure that there is adequate generation available to charge the battery storage.

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[31] CPUC Energy Division, *2019-20 IRP: Proposed Reference System Portfolio Validation with SERVM Reliability and Production Cost Modeling*, Nov. 6, 2019, at 17.

[32] *Flexible Capacity Deliverability Assessment*, 2019-2020 Transmission Planning Process Stakeholder Meeting, Nov. 18, 2019, at 20-29.

CalCCA is concerned that there is no opportunity for stakeholders to review the proposed busbar mapping and to provide informed input before the final portfolios along with resource mapping are conveyed to the CAISO. It is pertinent that stakeholders are kept in the loop in case the CAISO discovers issues with the proposed busbar mapping as they begin analyzing the resource portfolios in the 2020-2021 TPP cycle.

G. Proposed Aggregation Process for the 2020 PSP

1. For a particular resource type and zone, where the aggregated resources in LSE plans exceed the resource potential, this suggests that some portion of the selected resources are non-viable from an economic, environmental, or land use perspective. What level of exceedance over resource potential is acceptable, if any, before staff should reallocate resources when aggregating resource choices to form a PSP?

Staff suggest a refined approach to aggregating individual IRP resource choices in 2020. The refined approach entails clarifying for LSEs how information in their portfolios and broader plan filings will be used to inform the development of the 2020 PSP, reducing Commission staff's manual reallocation of MW values in LSE plans to better fit at the system level, reducing potential for errors; and identifying for stakeholders what will happen in the event that LSE portfolios, in aggregate, differ from the RSP adopted by the Commission.

Subsets of CCAs will coordinate procurement in particularly valuable, which should reduce the cases of aggregated resources in LSE plans exceeding the resource potential in certain areas. CalCCA recommends a 20 percent threshold exceedance level over resource potential given that resource specificity, particularly in the out years, will be subject to refinement based on market conditions and availability. Some level of flexibility is required and any such exceedance needs to be further studied in the preliminary CAISO TPP analysis to determine whether such exceedance trigger the need for any major transmission upgrade.

To understand how the 20 percent exceedance could be implemented, let us use the theoretical scenario included in the ALJ Ruling where the initial aggregation of LSE portfolios identifies 600 MW of FCDS wind in the *Carrizo* zone in 2022, which is 413 (=600-187) MW in excess of the FCDS capability of the existing transmission system. Rather than reallocating the entire 413 MW to the nearby zones, such as *Kern_Greater_Carrizo* and *Tehachapi*, only a portion of it, *i.e.*, 375.6 MW of will be reallocated and the remaining 224.5 MW will be modeled in Carrizo. The CAISO's preliminary TPP analysis will verify whether the additional 20 percent capacity, *i.e.*, 37.4 MW (=187 times 20 percent) could be accommodated without triggering the need for any transmission upgrades. CalCCA also notes that since the CAISO is expected to deploy its revised deliverability methodology in the 2020-2021 TPP, almost all zones would likely be able to accommodate more FCDS resources than envisioned based on the earlier methodology.

2. What showings should LSEs be required to make to demonstrate that deviations, if any, between the aggregation of LSE portfolios and the RSP are appropriate and necessary to better adhere to the IRP statutory requirements?

While the RSP provides a useful benchmark and starting point for the state's planning exercise, it does not and cannot reflect the individual needs and desires of each LSE, and the IRP process must not ignore insights and outcomes of individual LSE planning efforts. The IRPs under development by CalCCA's members are intended to meet both statewide policy goals, as well as local policy mandates and preferences. Many of these plans will aim to meet more aggressive GHG targets, incorporate local development preferences, require meeting load with renewables for each hour of the year, and incorporate greater demand-side management and beneficial electrification.

The likelihood that these plans will deviate from the RSP has increased recently as CCAs have turned their focus to resilient local solutions to mitigate the impacts of Public Safety Power Shutoffs, including traditional, customer-sited behind-the-meter solutions, as well as local microgrids with resources in front of the meter.[33] For these reasons, the strategies to achieve the state's goals are likely to differ from the strategies and mix selected by the RSP, and may result in an aggregated portfolio with greater costs borne by the LSEs that pursue those costs.

CalCCA supports requiring LSEs to provide supporting documentation and justification for these deviations, including qualitative and quantitative support. Qualitative evidence could include reference to local policy or legal requirements requiring deviation. Quantitative support could include analysis demonstrating portfolio compliance with overarching policy goals such as decarbonization and reliability, such as PCM assumptions and outputs. CCAs intend to make relevant quantitative data available to illuminate any plan deviations, subject to the restrictions of D.06-06-066 and the Public Records Act, and expect other market participants will do the same. The Commission should require LSEs to identify any deviations in an Appendix and provide all supporting qualitative and quantitative support as a part of the Appendix.

3. What criteria should Commission staff use to determine whether transmission upgrade needs identified by LSEs in their IRPs are appropriate to be reflected in the PSP and the TPP reliability base case adopted by the Commission?

Under the proposed Staff aggregation approach, LSEs may trigger an upgrade not identified in the RSP if the LSEs communicate that they are actively planning for the upgrades, and can justify the cost, timeline, and risks.

[33] *See, e.g.,* Redwood Coast Airport Renewable Energy Microgrid, located at https://redwoodenergy.org/community-choice-energy/about-community-choice/power-sources/airport-solar-microgrid/.

CalCCA recommends an alternative approach to addressing zone constraints, since addressing constraints through upgrades may be a superior solution to resource relocation. Since upgrades would be triggered mostly through collective impacts, it is unlikely that any individual LSE would have the needed visibility into other LSE plans to know there would be a need for an upgrade, so it is unlikely any individual LSE would be planning for upgrades resulting from collective impacts. That does not mean that CAISO would not find the upgrade to be cost effective when it examines the collective impacts, however. Thus, CalCCA recommends that where a zonal constraint is triggered, the Commission consult with CAISO on how such a constraint could be alleviated, rather than resorting immediately to relocation assuming such a constraint would not be cost effective to address.

4. Provide any other comments on the Commission staff-proposed aggregation approach, including any process suggestions for how LSEs can more effectively participate or give input to the planning process.

CalCCA generally does not object to Staff's proposed aggregation process as outlined in the Ruling.[34] In Staff's process of reallocating resources in oversubscribed zones, however, the Commission should provide affected LSE's, collectively, notice in a public posting and an opportunity to propose an alternative before performing the reallocation as specified in the Ruling.

[34] Ruling Seeking Comment at 33-36.

III. CONCLUSION

For all of the foregoing reasons, CalCCA respectfully requests consideration of the proposals specified herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

December 17, 2019

Respectfully submitted,

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EXHIBIT A

CalCCA Seven-Hour FOM Battery Storage Scenario

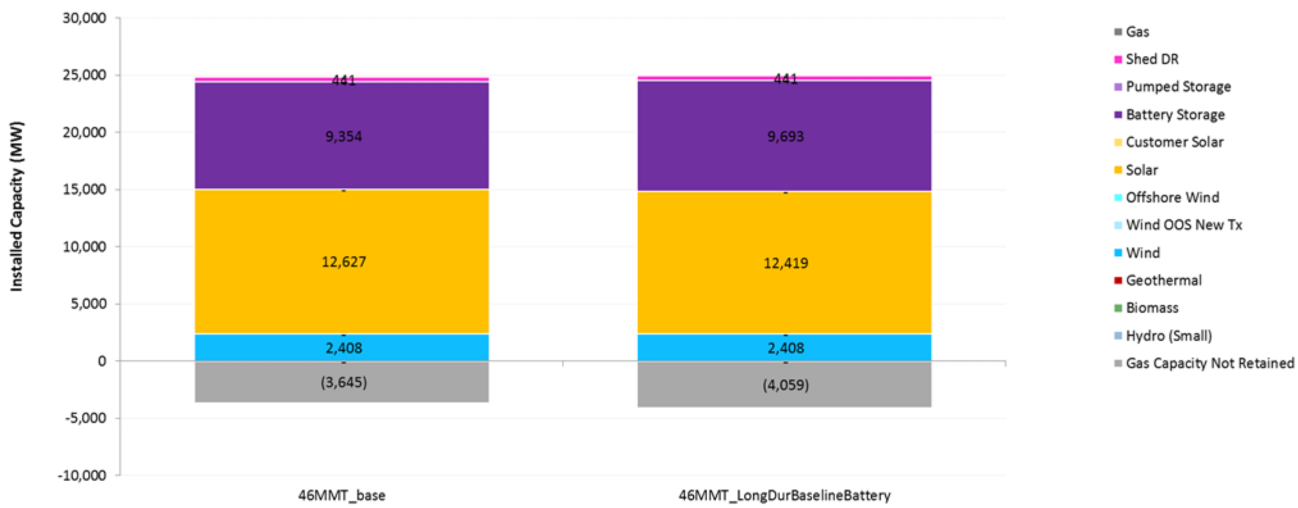
RESOLVE currently does not have the functionality to identify the optimal duration of storage to meet varying amounts identified in CAISO's LCR studies. To better understand how RESOLVE results might be affected by changing battery storage duration, CalCCA ran a sensitivity scenario using the Oct 4th 46 MMT Base Case, where we forced the baseline utility-scale FOM storage of about 1,479 MW by 2030 to all be 7-hour Li-Ion battery storage instead of the default 4-hour battery as a proxy for longer duration storage capacity. The results of this longer duration battery storage case shows that such higher duration storage reduces the need for the duration of the other storage resources, especially in the years 2022 and 2026.

RESOLVE does not allow for the flexibility to select different levels of battery storage capacity with different durations. Therefore, in order to have at least some Li-Ion battery storage with a longer duration, CalCCA used the feature of RESOLVE allowing users to fix the duration of the "baseline" battery storage only, forcing the assumed 4-hour baseline battery storage assumed in the 46 MT Base case (*i.e.,* 1,479 MW by 2030) to 7-hour duration. With the modified baseline, RESOLVE then "selects" the amount of battery discharge energy that is needed to meet the various constraints. The resultant average duration of that optimized built Li-Ion battery storage capacity (*i.e.*, the ratio of energy and capacity) is reduced in the case when the baseline battery storage had a longer duration (7-hour) versus in the cases when it has a shorter duration (4-hour). See the highlighted values in yellow in the table below that compares the Li-Ion storage duration by 2030 in the two cases.

	4-Hour Duration - 46 MMT				7-Hour Duration - 46 MMT			
Planned & Optimized Build	2020	2022	2026	2030	2020	2022	2026	2030
Planned Baseline Li_Ion Battery Duration	4.0	4.0	4.0	4.0	7.0	7.0	7.0	7.0
Optimized Build Li_Ion Battery Duration	-	4.0	3.5	3.7	-	1.9	2.5	3.4

Using longer duration storage also reduces total curtailments relative to the Base 46 MMT case and most importantly, reduces the need to retain the gas-fired generation in 2030 as shown in Figure 1 below. It reduces the dispatch of CCGT units, reducing the need to retain gas-fired generation. In particular, by 2030, more than 400 MW of additional gas capacity is not retained in the longer duration battery storage case relative to the 46 MMT base case.

Figure 1: A Comparison of Installed Capacity (MW) in the 46 MMT case with 4-hour vs. 7-hour Duration Baseline Li-Ion Battery Storage Capacity in 2030



As shown in Figure 2 below, the reduced reliance on the gas-fired generation (from 42,229 GWh to 41,118 GWh) is made up of a combination of increased duration of the battery storage dispatch, increased reliance on unspecified imports (increased from 27,397 GWh to 28,371), reduced exports (from 7,637 GWh to 7,137 GWh) and curtailments (from 5,237 GWh to 4,925 GWh). These findings show that the higher duration battery storage also reduces renewable curtailments as well as exports. In the November 6th cases when the imports are restricted for all hours to 5 GW, we did not find that the longer duration storage had any significant impact on the gas-fired generation retention, CCGT dispatch, unspecified impart, exports or curtailments.

Figure 2: A Comparison of Generation (GWh) in the 46 MMT case with 4-hour vs. 7-hour Duration Baseline Li-Ion Battery Storage Capacity in 2030